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May 5, 2003

Mr. Roger Kohn
Environmental Protection Specialist
USEPA Region 9
Air Division (AIR-3)
75 Hawthorne Street
San Francisco, CA 94105-3901

Subject: **Blythe Energy Project Phase II**
Caithness Blythe II, LLC Comments to the "Draft" PSD Permit

Dear Mr. Kohn:

Enclosed, please find three (3) copies of Caithness Blythe II, LLC's (CB II) comments on the draft EPA PSD permit issued for public comment on March 31, 2003. Our comments primarily address EPA's BACT requirements for emission concentration limits and several inconsistencies regarding the "draft" compliance conditions. We urge EPA to communicate with the Mohave Desert Air Quality Management District on certain language in the draft permit so the MDAQMD Final Determination of Compliance and the final EPA Permit are consistent in the requirements and conditions.

As you requested, we have enclosed a copy of our dry cooling analysis which was included with the California Energy Commission application for certification. We will also provide a copy of our Emission Reduction Credit package under separate cover as a "Confidential" filing.

If you have any questions, please do not hesitate to call me at (414) 475-2015.

Very truly yours,

Thomas Cameron

Thomas Cameron
Project Manager
Caithness Blythe II, LLC

attachment

Blythe Energy Project – Phase II
Comments on EPA Draft PSD Permit

Caithness Blythe II (CB II) has proposed to construct the Blythe Energy Project – Phase II (BEP II) consisting of the addition of two combustion turbine generators operating in combined cycle at the existing Blythe Energy Project (BEP) in Blythe, CA. Although the facilities are not under common ownership, the same operating Company will most likely operate the facility. Therefore, CB II has chosen Siemens Westinghouse V84.3A combustion turbines, which are the same turbines in use at BEP. Using the same turbines will make it easier for the operators to operate, make repairs, and reduce inventory costs for both plants. The project area is designated as Federal attainment or unclassified for nitrogen oxides (NO_X), carbon monoxide (CO), and particulate matter (PM_{10}). Since the proposed combustion turbines will have significant emissions of NO_2, CO, and PM_{10}, BEPII submitted a PSD application to EPA Region IX. EPA Region IX issued a draft Prevention Of Significant Deterioration (PSD) permit for BEP II, which is contained within EPA's Ambient Air Quality Impact Report (NSR 4-4-4, SE 02-01). The draft permit proposes emission limits for NO_X, CO, and PM_{10} to meet the Best Available Control Technology (BACT) requirements of the federal PSD regulations. CB II has reviewed the draft PSD permit and proposed emission limits, and based upon this review, CB II provides the following comments on the draft permit.

1. EPA Region IX has proposed a NO_X BACT emission limit of 2.0 ppmvd at 15% O_2 (1-hour average) in Condition X.D of the draft permit. EPA Region IX identified several combustion turbine projects that have been permitted at the 2.0-ppm limit, including one facility[1] that has begun operation with preliminary data showing compliance with this limit. After a careful and thorough review of these facilities and a review of recent permit decisions in Region IX, CB II believes that the proposed 2.5 ppm limit in the Mojave Desert Air Quality Management District (MDAQMD) Preliminary Determination Of Compliance (PDOC) is consistent with federal EPA BACT as determined on a case-by-case basis in accordance with 40 CFR 52.21 and other agency guidance. The basis for our conclusion is provided below.

   i. All of the projects with lower emission limits identified by EPA Region IX are located in ozone non-attainment areas and are required to meet Lowest Achievable Emission Rate (LAER).

   All of the projects cited are located in ozone non-attainment areas and were required to install Lowest Achievable Emission Rate (LAER) technology for NO_X emissions. As discussed in EPA's *1990 New Source Review Workshop Manual*, LAER determinations must be included in the BACT analysis but may be "eliminated from consideration because they have unacceptable energy, economic, and environmental impacts". Also, in the Environmental Appeals Board (EAB) decision for the Three Mountain Power project (PSD Appeal No. 01-05), "LAER can be more stringent than BACT". When considering the energy, economic, and environmental impacts for BEP II on a case-by-case basis, the proposed 2.5 ppm NO_X limit meets the BACT requirements. Furthermore, as demonstrated below, the proposed BACT limit is as stringent and perhaps more stringent than several of these LAER determinations when considering the specifics of the BEP II project.

[1] ANB Blackstone Generating (MA). Ozone non-attainment area, LAER required.

ii. 2.0 ppm on a 1-hour average has not been demonstrated in practice for Siemens Westinghouse V84.3A turbines, while 2.5 ppm 1-hour average has been demonstrated.

EPA Region IX's discussion of the NO_X BACT analysis in the draft PSD permit states that "several recently permitted California power plants, which are *similar if not identical in all material respects* (emphasis added) to the BEP II facility, are required to meet a LAER or BACT emission rate of 2.0 ppm". As described above however, the NO_X emissions rate from the proposed Siemens Westinghouse V84.3A turbines will be nearly two to three times greater than the turbine NO_X emissions rate from all of the cited California projects. Furthermore, the Siemens Westinghouse V84.3A NO_X emissions rate will be two and one-half times greater than the actual reported emission rate from the ANP Blackstone cited in the Region IX analysis as meeting this limit. This higher NO_X emission rate from the Siemens Westinghouse V84.3A turbines makes the BEP II project distinctly dissimilar from the projects identified by EPA Region IX.

iii. At 2.5 ppm, BEP II would be required to achieve a NO_X reduction of 90.3%, which is greater than the SCR NO_X reduction for any of the identified LAER projects.

CB II will utilize Siemens Westinghouse V84.3a turbines for BEP II. These combustion turbines have a NO_X emissions rate from the turbine of 25.0 ppm at 15% O_2. The NO_X control selected by CB II is selective catalytic reduction (SCR), which is consistent with all BACT and LAER subject projects with a generating capacity greater than 100 megawatts (MW). To achieve 2.5 ppm at the stack, the SCR would need to achieve a 90.3 percent reduction of NO_X emissions. The highest level of NO_X reduction required by the projects identified by EPA Region IX is 87 percent.

BACT is defined under 40 CFR 52.21 as "an emissions limit based on the **maximum degree of reduction**....on a case-by-case basis". This definition implies that the driving force for the emission limit is the overall reduction of the subject pollutant. All of the LAER projects in California cited by Region IX[2], except for the San Joaquin Valley Energy Center, proposed GE 7F combustion turbines that can achieve a NO_X emission rate from the turbine of 9.0 ppm. The San Joaquin Valley Energy Center proposed Siemens Westinghouse 501F turbines that can achieve 15 ppm from the turbine. These California projects were permitted as LAER with proposed SCR systems that required a NO_X control efficiency of 78 (GE 7FA) to 87 (Siemens Westinghouse 501 FD) percent. Therefore, the 90.3 percent reduction required for BEP II to achieve 2.5 ppm is higher than numerous LAER projects in California. If BACT is set at 2.0 ppm as proposed in the draft PSD permit, BEP II would be required to achieve a 92.2 % reduction, which is significantly higher than these LAER determinations.

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[2] Sunrise Power Project, Western Midway Sunset, San Joaquin Valley Energy Center, Avenal Energy Center, Tesla Power Project, and East Altamont Energy Center. All projects located in ozone non-attainment areas and LAER was required.

In EAB's decision for Knauf Fiber Glass I (PSD Appeal Nos. 98-3 through 98-20), EAB determined that "the use of the same add-on controls may not yield the same emission rate when deployed on different processes". The EPA has permitted numerous New Source Review (NSR) subject combustion turbine projects with SCR at varying BACT NO_X permit limits (see Attachment 1). These varying permit limits signify that BACT is applied on a case-by-case basis, and when considering the maximum degree of reduction achievable by SCR for that project, different BACT emission rate limits are applicable. This is consistent with guidance provided in the 1990 NSR Workshop Manual which noted that "the objective of the top-down BACT analysis is to not only identify the best control technology, but also a corresponding performance level for that technology considering source-specific factors".

CB II asserts that the SCR control efficiency required to achieve 2.0 ppm (a 92.2% reduction) for the Siemens Westinghouse V84.3A turbines has not been demonstrated in practice. None of the projects identified by EPA Region IX requires a NO_X reduction from SCR technology that is equivalent to or greater than the reduction that would be required for BEP II to achieve 2.0 ppm. Furthermore, the required SCR control efficiency to meet 2.5 ppm is greater than the SCR efficiency for all of the projects identified by EPA Region IX.

EPA's 1990 New Source Review Workshop Manual states that the first step in the BACT analysis when ranking control technologies is to identify the top control level based upon "control efficiencies (percent of pollutant removed)"[3]. The proposed NO_X BACT emission rate of 2.5 ppm will require an SCR control efficiency that is greater than all of the 2.0 ppm projects identified by EPA Region IX. Therefore, a NO_X BACT emission rate of 2.5 ppm is consistent with EPA BACT guidance and the requirement to achieve the "maximum degree of reduction…on a case-by-case basis".

iv. The requirement to achieve LAER will add significant costs.

If achievable, the requirement to meet 2.0 ppm would have significant economic impacts. A cost estimate from Siemens Westinghouse for an SCR to achieve 2.0 ppm had the following costs and operating impacts, **on a per turbine basis:**

Additional Catalyst:	$415,000
Engineering:	$210,000
Installation:	$75,000
Reduction in Capacity:	225 kw

Based upon these costs, an incremental cost effectiveness of $22,300 per ton removed was calculated in accordance with the 1990 New Source Review Workshop Manual

[3] Section III.C, Page B.8.

(calculations provided in Attachment 2). As noted in the 1990 New Source Review Workshop Manual, "comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies". CB II believes this incremental cost effectiveness, and overall project cost increase of $1.4 million, to be excessive. A review of the permitted emission rates in Attachment 1 demonstrate that there are no known combustion turbine projects permitted with a NO_X emission rate of 2.0 ppm in an area designated as attainment/unclassified for ozone. When considering whether costs are excessive, the 1990 New Source Review Workshop Manual states that the "costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent **BACT** determinations". Since there are no PSD BACT determinations with a NO_X emission rate of 2.0 ppm, there are no projects for comparison with BEP II. Consequently, BEP II would incur costs that no other facility subject to PSD BACT has yet to bear. Therefore, CB II believes these additional costs are excessive and unwarranted for BEP II.

v. Collateral Adverse Environmental Impacts

In addition to the economic impacts, there will be a potential significant environmental impact associated with the requirement to achieve 2.0 ppm NO_X emissions. The most significant impact may be in the severe ozone non-attainment area near Los Angeles. The vast majority of the generation from BEP II will flow east into the Los Angeles area. The application of additional catalyst to achieve 2.0 ppm NO_X emissions will reduce total BEP II generation output by 0.45 MW. This displaced generation will need to be replaced during critical periods when capacity is in short supply. During the recent energy crisis in California, numerous industrial facilities were allowed to operate their backup generators so that the California could meet the electricity demand requirements for the public. A review of the backup generators compiled by CARB lists over 2,000 backup generators in the South Coast area with a total generating capacity of nearly 1,700 MW. These generators have an average NO_X emission rate of 26.4 lb/MWh. A 0.5 ppm reduction in NO_X emissions will reduce the NO_X emission rate from BEP II by less than 7 lbs/hr. During a capacity shortfall that required industrial facilities to operate their backup generators, the 0.45 MW of generation lost would result in NO_X emissions of nearly 12 lbs/hr from these generators. Therefore, during a capacity shortfall that would likely occur during the ozone season, a reduction in 7 lbs/hr of NO_X emissions from an ozone attainment/unclassified area could cause an increase in NO_X emissions of 12 lbs/hr in an area designated as severe non-attainment for ozone.

vii. Discontinued Units

CB II has proposed using the Siemens Westinghouse V84.3A combustion turbine generators for BEP II. These units have been discontinued by Siemens Westinghouse and therefore will no longer be manufactured. There are a limited number of units available which have not been installed as yet. CB II owns 2 units for a failed project in

Arizona. Siemens Westinghouse will not be investing R&D funds to improve the performance of these machines. The 2.0 ppm NOx emission limits which have been proposed by EPA for BEP II represents the lowest NOx level requirement for any of the V84.3A combustion turbines which have been permitted to date.

viii. Common Operations for BEP and BEP II

CB II proposes to construct the BEP II project on the same parcel of land as the BEP project. As required by MDAQMD, BEP II is offsetting VOC's and SOx as if they are a combined project. Therefore CB II is securing emission reduction credits equivalent to both BEP (approximately 24 tons each VOC and SOx) and BEP II (approximately 24 tons VOC and SOx) combined emissions for VOC's and SOx (approximately 48 tons VOC and SOx). Therefore CB II is already mitigating more than a single project would otherwise be required to offset. Additionally, the operation staff for BEP may be operating and maintaining BEP II. Having common compliance conditions and emissions criteria for the two projects will be beneficial for managing the compliance at the two facilities. Having a common plant design is critical to managing this process.

From the above analysis, CB II believes the proposed NO_X BACT limit of 2.5 ppmvd at 15% O_2 meets BACT requirements on a case-by-case basis for the following reasons:

i. A 2.0 ppm NO_X emission rate has not been demonstrated in practice for a Siemens Westinghouse V84.3A turbine while 2.5 ppm has been demonstrated in practice.

ii. The required NO_X reduction for the SCR to meet 2.5 ppm (90.3%) meets the "maximum degree of reduction" required by BACT and is better than the SCR performance (<87%) for numerous LAER facilities permitted at 2.0 ppm in California.

iii. The costs to reduce the NO_X emissions from the most stringent PSD BACT determination of 2.5 ppm to the established LAER limit of 2.0 ppm have not been borne by any other facility in an ozone attainment/unclassified area and therefore are by definition excessive.

iv. The lost generation capacity resulting from the additional SCR catalyst could potentially transfer NO_X emissions from an ozone attainment/unclassified area to a severe non-attainment area

v. The Siemens Westinghouse V84.3A combustion turbines have been discontinued and Siemens Westinghouse does not plan to improve the performance of the units.

vi. CB II is offsetting the emissions according to the MDAQMD rules as if the two projects were a combined source.

vii. BEP and BEP II may be operated by a common staff and equivalent compliance conditions and designs are important to managing this process.

2. The emission levels specified under Condition IV.B.3.ii regarding affirmative defense in the event of malfunction do not appear to have any basis. These limits are not consistent with the averaging periods for the ambient air standards for each pollutant. The NO_2 ambient air quality standard has an annual averaging period. The CO ambient air quality standard on the other hand has a 1-hour averaging. CB II believes the facility should have an affirmative defense if it meets the other criteria of Condition IV.B.3 without being held to emission limits that were not established to protect the air quality.

   This malfunction language may also provide an incentive for the facility to shutdown and then startup after a malfunction to meet the requirements under Special Condition X.G. since these limits are easier to comply with than the affirmative defense emission levels. This action will allow the facility to comply with the conditions of the permit yet result in higher overall emissions from the facility.

   Therefore, CB II requests EPA to delete Condition IV.B.3.ii in its entirety.

3. Condition IV.B.3.vi contains language that is not applicable to the BEP II project. BEP II does not have a production process and therefore has no "material feed". The turbines fire natural gas exclusively and therefore cannot switch to alternative, less polluting fuels. CB II requests EPA to delete this language from the permit.

4. Condition VIII states that the facility must comply with the applicable provisions of 40 CFR 63. The facility is a minor source of HAP emissions and therefore not subject to any MACT standards. CB II requests EPA to delete "40 CFR 63" from this condition.

5. Special Condition X.B. requires SCR catalyst installation prior to first fire and SCR operation from the date of first fire so that "emissions are at or below" the permitted levels. The facility can not comply with this condition. The commissioning of a combustion turbine requires that first fire occur without the SCR catalyst in place to establish proper operation of the turbine and ancillary equipment. This will prevent the SCR catalyst from being damaged during the initial commissioning of the turbine. OEMs will not guarantee catalyst performance for its useful life if the catalyst is installed at 1st fire of the combustion turbine.

   The permit, as well as 40 CFR 60.8, requires performance testing within 60 days after reaching maximum firing rate or within 180 days after startup. The facility cannot comply with the NO_X emission limit without the SCR, consequently the performance testing deadline also establishes a deadline for the SCR installation. Therefore, CB II requests EPA to delete this condition.

6. Special Condition C.1 requires annual emissions testing for NO_X and CO emissions. The facility will have CEMS for measuring NO_X and CO emissions. These CEMS will be installed, operated, and certified in accordance with Condition X.H. Since emissions of

NO_X and CO will be continuously monitored by certified CEMS, annual emissions testing for these two pollutants is unnecessary. CB II requests EPA to delete the annual testing of NO_X and CO from the permit.

7. Special Conditions X.D, X.E, and X.F.c. require compliance with the NO_X and CO emission limits from the date of startup. Compliance with these limits is not possible from the date of first fire since the SCR will not be installed at that time. Initial operation of the combustion turbines will require a shakedown period prior to achieving sustainable steady state operation of the turbine. Additionally, since certified CEMS and performance testing are not required until "60 days after reaching maximum production rate or 180 days after startup", there is no mechanism for demonstrating compliance with these limits from the date of startup. CB II proposes to comply with the emission limits in the permit in accordance with the timeframe established for the performance testing pursuant to Condition X.C, consistent with the provisions of 40 CR 60.8.

8. The NO_X, CO, and PM10 emission limit conditions (Conditions X.D, E, & F) do not include language that these limits do not apply during periods of startup and shutdown. Condition X.G limits the emissions from the turbines during periods of startup and shutdown. CB II proposes the following permit language to replace the existing language for Conditions X.D, E, & F:

   "The Permittee shall not discharge or cause the discharge of [NO_X, CO, PM_{10}] from each combustion turbine into the atmosphere in excess of [applicable permit limit]. The Permittee shall achieve compliance with these limits no later than the date of the initial performance testing as required under Condition X.C. These limits shall not apply during periods of startup and shutdown as defined under Condition X.G."

9. Condition X.H.1 requires CEMS installation prior to startup. Condition I.2. requires CEMS certification to begin no later than the 60 days after reaching full load or 180 days after startup to comply with 40 CFR 60.13. Having uncertified CEMS installed for up to 180 days will provide no environmental benefit. CB II proposes to install, operate, and certify the CEMS at BEP II in accordance with the schedule provided in 40 CFR 60.13 as follows:

   "The CEMS shall be installed and operational prior to the initial performance testing in accordance with 40 CFR 60.13(b). In accordance with 40 CFR 60.13(c), the facility will evaluate the performance of the CEMS during the initial performance testing required under 40 CFR 60.8 or within 30 days thereafter."

10. Condition X.C.1 references "base load" while Condition X.I.2 references "full load operation" for establishing the performance testing schedule. CB II proposes that this language should be consistent with the language of 40 CFR 60.8(a), which specifies that performance testing be completed within 60 days after achieving "maximum production rate". Maximum production rate for the turbines is equivalent to maximum firing rate.

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Comments on EPA Draft PSD Permit

11. As discussed at out meeting on April 24, 2003, the draft permit interchanges "commercial startup", "initial startup", and "startup" in Conditions II, X.B., X.C., X.D., X.E., X.F., X.H., and X.I. CB II requests that any condition based upon initial operation of the facility be consistent with 40 CFR 60 Subpart A and state "initial startup".

12. The PDOC issued by the MDAQMD and the draft PSD permit issued by EPA Region IX use different language for establishing emission limits and operating requirements for BEP II. CB II requests that EPA Region IX consider replacing the language in the draft PSD permit with the language in the PDOC, where applicable. Having consistent language in these two permits for emission limits; startup and shutdown emissions; CEMS requirements; testing requirements; recordkeeping and reporting requirements; and control equipment requirements will facilitate future facility compliance.

Blythe Energy Project – Phase II
Comments on EPA Draft PSD Permit

ATTACHMENT 1
LIST OF RECENT PSD BACT NO_x PERMIT LIMITS

Blythe Energy Project – Phase II
Comments on EPA Draft PSD Permit

PSD NO_x BACT Limits From January 2001 To Present Large Natural Gas Fired Combined Cycle Combustion Turbine Projects					
Facility	**State**	**Turbine Model**	**Permit Date**	**Emission Limit(s)[1]**	**Controls**
Tenaska Alabama III Partners	AL	GE 7FA	1/01	3.5	SCR
Blount County Energy	AL	F Class CTs w/HRSGs and steam generator	1/01	3.5 (3 hr)	SCR
Autaugaville	AL	F Class CTs	1/01	3.5	Dry Low NO_X, SCR
GenPower – Kelly, LLC	AL	GE 7FA	1/01	3.5	Dry Low NO_X, SCR
Hillabee Energy Center	AL	Westinghouse 501F	1/01	3.5	Dry Low NO_X, SCR
CPV Gulf Coast	FL	GE 7FA	01/01	3.5 (3-hr)	DLN combustors, SCR
Covert Generating	MI	Mitsubishi 501G	01/01	2.5 (24-hr)	DLN combustors, SCR
Washington Energy	OH	GE 7FA	01/01	3.5 (1-hr)	DLN combustors, SCR
Badger Generating	WI	Mitsubishi 501G	02/01	2.5 (24-hr)	DLN combustors, SCR
Alexander City	AL	GE 7FA	2/01	3.5 (1 hr)	Dry Low NO_X, SCR
Goldendale	WA	F Class CT	2/01	2.0 (3 hr)	Dry Low NO_X, SCR
Duke Energy Murray	FL	GE 7FA	2/01	3.5 (24 hr)	Dry Low NO_X, SCR
Blythe Energy Project	**CA**	**Siemens V84.3A**	**3/01**	**2.5 (1 hr)**	**Dry Low NO_X, SCR**
Chehalis Generating	WA	GE 7FA	03/01	3.0 (1-hr)	DLN combustors, SCR
Waterford Energy	OH	GE 7FA	03/01	3.5 (1-hr)	DLN combustors, SCR
Calendonia Power	MS	GE 7FA	3/01	3.5	Dry Low NO_X, SCR
Columbia Energy	SC	GE 7FA	4/01	3.5	Dry Low NO_X, SCR
Goat Rock	AL	GE 7FA	4/01	3.5	Dry Low NO_X, SCR
Morrow Bay Power	CA	GE PG7241	5/01	2.5 (1 hr)	Dry Low NO_X, SCR
CPV – Atlantic Power	FL	GE 7FA	5/01	3.5 (24 hr)	Dry Low NO_X, SCR
Three Mountain Power	CA	GE 7FA or Westinghouse 501F	5/01	2.5 (1 hr)	Dry Low NO_X, SCR
Duke Energy Kankakee	IL	GE 7FA	05/01	2.5 (24-hr)	DLN combustors, SCR
Sugar Creek Energy	IN	GE 7FA	05/01	3.0 (3-hr)	DLN combustors, SCR
Kiamichi Energy	OK	GE 7FA	05/01	9.0 (3-hr, w/o DF) 15.0 (3-hr, w/ DF)	DLN combustors
Brandy Branch Generating Center	FL	Unknown	05/01	3.5 (3-hr)	DLN combustors, SCR
Stanton Energy Center	FL	GE 7FA	05/01	3.5 (3-hr)	DLN combustors, SCR
Mint Farm	WA	GE 7FA	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR

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PSD NO_x BACT Limits From January 2001 To Present Large Natural Gas Fired Combined Cycle Combustion Turbine Projects					
Facility	**State**	**Turbine Model**	**Permit Date**	**Emission Limit(s)**[1]	**Controls**
Longview	WA	Westinghouse 501F	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR
Longview	WA	GE 6FA	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR
Longview	WA	GE 7FA	6/01	3.0 (24 hr) 2.5 (annual)	Dry Low NO_X, SCR
Vigo Energy Facility	IN	GE 7FA	06/01	3.0 (3-hr)	DLN combustors, SCR
Lawrenceburg Energy	OH	Unknown	06/01	3.0 (3-hr)	DLN combustors, SCR
Hines Energy (FPC)	FL	Westinghouse 501F	6/01	3.5 (24 hr)	Dry Low NO_X, SCR
Calpine Osprey Energy	FL	Westinghouse 501F	7/01	3.5 (24 hr)	Dry Low NO_X, SCR
Xcel Energy	MN	Westinghouse 501F	7/01	4.5 (3 hr)	Dry Low NO_X, SCR
Duke Energy Autauga, LLC	AL	F Class CTs	07/01	3.0 (3-hr)	DLN combustors, SCR
Mirant Wyandotte, LLC	MI	GE 7FA	07/01	3.5	DLN combustors, SCR
Midland Cogen	MI	Unknown	07/01	3.0 (3-hr) w/o SI 3.5 (3-hr) w/ SI	DLN combustors, SCR
Contra Costa Power	CA	GE 7FA	7/01	2.5 (1 hr)	Dry Low NO_X, SCR
CPV Pierce Power	FL	GE 7FA	8/01	2.5 (24 hr)	Dry Low NO_X, SCR
Redbud Power	OK	Siemens Westinghouse V84.3a	08/01	3.5 (24-hr)	DLN combustors, SCR
Fremont Energy Center	OH	GE 7FA	08/01	9 (2-hr) w/o DF 15 (ann) w/ DF	DLN combustors, SCR
Smith Pacola Power	OK	GE 7FA	08/01	3.5 (1-hr)	DLN combustors, SCR
Broward Energy Center	FL	Unknown	08/01	9 (monthly) w/o DF 15 (monthly) w/ DF	DLN combustors, SCR
Curtis H Stanton Energy	FL	GE 7FA	9/01	3.5 (24 hr)	Dry Low NO_X, SCR
El Paso Belle Glade Energy Center	FL	Unknown	09/01	2.5 (3-hr)	DLN combustors, SCR
Duke Energy Dale, LLC	AL	GE 7FA	09/01	2.5 (3-hr)	DLN combustors, SCR
Satsop CT Project	WA	GE 7FA	10/01	3.5	DLN combustors, SCR
Hot Springs Power	AR	Westinghouse 501G	11/01	3.5	DLN combustors, SCR
Stephens Energy	OK	GE 7FA	12/01	2.5	DLN combustors, SCR
Panda Culloden Power, LLC	WV	GE 7FA or Westinghouse 501F	12/01	3.5 w/o DF 4.0 w DF	DLN combustors, SCR

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Comments on EPA Draft PSD Permit

PSD NO_x BACT Limits From January 2001 To Present Large Natural Gas Fired Combined Cycle Combustion Turbine Projects					
Facility	**State**	**Turbine Model**	**Permit Date**	**Emission Limit(s)[1]**	**Controls**
Effingham County Power, LLC	GA	GE 7FA	12/01	3.0	DLN combustors, SCR
Tenaska Virginia Partners (Fluvanna)	VA	GE 7FA	01/02	3.0 (3-hr)	DLN combustors, SCR
Wansley Power, LLC	**GA**	**Siemens Westinghouse V84.3a**	**01/02**	**3.0 (1-hr)**	**DLN combustors, SCR**
CPV Cana	FL	GE 7FA	02/02	2.5 (24-hr)	DLN combustors, SCR
Lawton Energy	OK	GE 7EA	05/02	3.5	DLN combustors, SCR
Westlake Energy	KY	GE 7FA, Westinghouse 501F, or Siemens Westinghouse V84.3a	05/02	2.5 (3-hr)	DLN combustors, SCR
Westward Energy	**OR**	**Siemens Westinghouse V84.3A**	**7/02**	**2.5 (3 hour)**	**DLN combustors, SCR**
Sumas Energy	WA	Siemens Westinghouse	08/02	2.0 (3-hr)	DLN combustors, SCR
Genova Arkansas I	AR	GE 7FA, Westinghouse 501F, or Mitsubishi 501F	08/02	3.5	DLN combustors, SCR
Henry County Power	VA	GE 7FA	11/02	2.5 (3 hr)	DLN combustors, SCR
Mirant Danville	VA	GE 7FA	12/02	2.5 (3 hr)	DLN combustors, SCR

[1] All emission limits are in ppmvd at 15% O_2

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ATTACHMENT 2
INCREMENTAL NO_x CONTROL COSTS

Blythe Energy Project – Phase II
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Blythe Energy Power - Phase II
Incremental Economic Analysis For NOx Emissions From 2.5 ppm to 2.0 ppm

NOx Emissions at 2.5 ppm (tpy)[1]	70.0	Total Hours	8,760
NOx Emissions at 2.0 ppm (tpy)	56.0		

Direct Installation Costs		***Total Direct Installation Cost***	$210,000
Indirect Installation Costs	Engineering		$75,000
	Contingencies[2]	(Estimated at 10% of the catalyst, installation, & engineering costs)	$70,000
		Total Indirect Installation Cost	$145,000
Direct Annual Costs ($/yr)	Catalyst Replacement (3 yrs @ 8% interest, $415,000)		$161,032
	Performance Loss (225 kw @ $.05/kWh)		$98,550
		Total Direct Annual Cost	$259,582
Indirect Annual Costs ($/yr)	Property Taxes, Insurance and Administration (0.04, installation and catalyst costs)		$28,000
	Capital Recovery (0.14903 x (Installation & Engineering))		$52,906
		Total Annual Cost	$312,488
		NOx Controlled (tons/yr)	14.0
		Incremental Control Cost ($/ton NOx)	$22,321

[1] Excludes startup & shutdown emissions which will not be reduced by the SCR.

[2] Siemens Westinghouse provided a more conservative contingency of $850,000.

Blythe Energy Project

Dry Cooling Economic Analysis

FINAL

Prepared for

CAITHNESS

By

MONTGOMERY WATSON HARZA

Energy & Infrastructure
January 2002
Report # 20549-081-0001

TABLE OF CONTENTS

SECTION

1. INTRODUCTION

MWH Energy & Infrastructure was asked to compare the capital and operations and maintenance (O&M) costs for wet and dry cooling systems and the effect of dry cooling on heat rate for a 2x1 combined cycle power plant in Blythe, California. The impact of dry cooling on an inlet chilling system was also analyzed. Additionally, values associated with water consumption and treatment were evaluated as were the visual and noise impacts of dry cooling.

2. EXECUTIVE SUMMARY

Capital costs for the dry cooling arrangement, including interest during construction (10%) were estimated to exceed capital costs for the wet cooling arrangement by approximately $22,700,000.

The dry cooled arrangement O&M costs are predicted to exceed those of the wet cooled system by approximately $308,000 annually. The net present value of this escalated at 2.5% with an interest rate of 10% for 30 years is $3,280,000.

At high ambient temperatures, the heat rate for a dry cooled plant was approximately 6.5% higher than a wet cooled plant. At low ambient temperatures the heat rate was calculated to be approximately 1% higher for the dry cooled arrangement. On an annual average, the heat rate was calculated to be 2.0% percent higher for the dry cooled arrangement.

ASSUMPTIONS

The plant is comprised of 2 Siemens V84.3A combustion turbines and a Siemens K-N steam turbine; the plant is nominally rated at 520 MW.

Heat rate calculations were performed using the GateCycle program. The output from a fully rated V84.3A was used.

A value of $0.025/kWh was used for calculating costs resulting from electrical energy use. An interest rate of 10% was used for interest during construction and calculating the net present value (NPV) of the O&M costs. O&M costs were escalated at a rate of 2.5% for thirty years to determine their NPV.

Climatic data from "Solar and Meteorological Surface Observation Network 1961-1990" were used to select average values of relative humidity for dry bulb temperatures of interest. The relationship between dry bulb temperature and relative humidity for Blythe is tabulated in Figure 1.

3. DESCRIPTION OF WET COOLING SYSTEM

The wet cooled water/steam cycle arrangement used for the GateCycle analysis consisted of a steam surface condenser, a cooling tower, circulating water pumps, condensate extraction pumps, and two triple pressure reheat heat recovery steam generators (HRSG).

The inlet chilling system for the wet cooling evaluation included an evaporative condenser to transfer the heat from the refrigerant to the environment. The chilling system was sized at 11,000 tons. The ammonia overfeed system was modeled to cool the combustion turbine inlet air from inlet conditions of 110°F dry bulb and 75°F wet bulb to 50°F dry bulb. The coefficient of performance for the chilling system ranges from 5 to 6 depending on ambient conditions. The maximum parasitic load for the system is approximately 8 megawatts.

A GateCycle report for conditions of 100°F and 20% relative humidity is presented as Figure 2. The heat balance includes the wet tower for the water steam cycle and the evaporative condenser for the chilling system.

The water treatment system for the wet cooled system assumed a brine concentrator to process plant waste streams (primarily cooling tower blowdown and HRSG blowdown) and systems to process raw water for demineralized and potable water use. The brine from the brine concentrator is routed to on site evaporation ponds. Two eight-acre evaporation ponds are provided to evaporate a maximum brine rate of 18 gpm (one pond will provide enough surface area for evaporation of 18 gpm, the second pond is provided for upset and maintenance conditions). The maximum power requirement for the water treatment system is approximately 2 MW; average power requirements are approximately 1.3 MW.

Plant water consumption is composed primarily of evaporation from the cooling tower; the second biggest contributor is evaporation from the chilling system's evaporative condenser. Annual water consumption is predicted to be approximately 3300 acre feet per year.

A third site production well would be required at the Blythe site for the wet cooled arrangement. Production wells are sized at 3000 gpm for this plant

4. DESCRIPTION OF DRY COOLING SYSTEM

The dry cooled water/steam cycle arrangement used for the GateCycle analysis consisted of an air cooled condenser, condensate extraction pumps, and two triple pressure reheat heat recovery steam generators (HRSG).

The inlet chilling system for the dry cooling evaluation included an air cooled condenser to transfer the heat from the refrigerant to the environment. The chilling system was sized at 11,000 tons. The ammonia overfeed system was modeled to cool the combustion turbine inlet air from inlet conditions of 102°F dry bulb and 75°F wet bulb to 50°F dry bulb.

A design limit of 102°F was selected in order to keep the dry condenser inlet chilling system capital costs reasonable and comparable to the evaporatively cooled system. This reduced design point will result in reduced chiller plant capacity for approximately 330 hours annually; this includes approximately 24 hours of extreme high dry bulb temperatures during which the chilling system would be inoperable. Increasing the dry bulb temperature much beyond 102°F will result in atypical and impractical system design pressures (above 300 psi) due to the higher condensing temperatures and will require substantially higher compressor/motor capacity as well as higher medium voltage transformer capacities.

The coefficient of performance for the chilling system ranges from 2.4 to 3.5 depending on ambient conditions. The maximum parasitic load for the system is approximately 13 megawatts.

A GateCycle report for conditions of 100°F and 20% relative humidity are presented as Figure 3. The heat balance was modeled with separate air cooled condensers for the water steam cycle and chilling system, as the process fluid in one condenser is water/steam and ammonia in the other.

The demineralized and potable water treatment systems for the dry cooling arrangement are assumed to be the same as those provided for the wet cooled plant. A brine concentrator is also provided to process the streams from HRSG blowdown and water treatment system reverse osmosis (RO) unit waste (RO unit waste is also part of the wet system waste stream but it is small in comparison to the blowdown streams). A surface area of approximately three acres would be necessary to evaporate the waste stream at design conditions; two three acre ponds are included in the cost analysis. The maximum power requirement is estimated to be about 20% of that for the wet cooling arrangement or about 400 kW, average power would be about 65% of this.

Annual water consumption is estimated to be approximately 200 acre feet per year.

5. CAPITAL COSTS

Capital costs for the dry cooling arrangement, including interest during construction (10%) were estimated to exceed capital costs for the wet cooling arrangement by approximately $22,700,000.

Included in the cost estimate is a value of $2,000,000 for engineering and material costs to the reference plant design for the selected generating equipment. Changes to the reference plant design will be required for the electrical systems (auxiliary transformers, bus duct, power distribution, duct bank) because of the large electrical load imposed by the air cooled condenser compared to the combination of cooling tower fans and circulating water pumps and the 5 MW difference between power requirements for the chilling systems; the dry cooling parasitic loads are approximately 8.5 MW higher than the wet cooling systems. Engineering costs will be necessary for redesign of the steam turbine hall in the vicinity of the steam turbine to accommodate a 20-foot diameter steam duct and its connections to the low pressure steam turbine. While difficult to accurately quantify, engineering costs and increased material costs will be necessary; the estimated value of $2,000,000 is likely to be on the low side of actual costs.

Capital costs were obtained from budgetary estimates from equipment vendors or from similar equipment purchased for different plants.

Capital costs are tabulated in Figure 4.

6. Operating and Maintenance Costs

The dry cooled arrangement O&M costs are predicted to exceed those of the wet cooled system by approximately $308,000 annually. The net present value of this escalated at 2.5% with an interest rate of 10% for 30 years is $3,280,000.

Electrical energy costs are higher for the dry cooled system. Electrical energy for cooling tower fans, water treatment systems, air cooled condenser fans, chilling system loads, and circulating water pumps were evaluated. Other plant auxiliary loads were expected to remain relatively unaffected by the method of cooling.

A 95% plant capacity factor was used for energy calculations. Average power demand for the cooling tower fans and air cooled condenser fans was estimated to be 70% of maximum demand. Average power demand for the water treatment plants was estimated to be 65% of maximum demand. Average power demand for the well pump was estimated to be 60% of maximum demand (No well pump was included in the dry cooled analysis, it is anticipated that the Blythe I well pumps would be able to satisfy Blythe II's requirements or a low capacity production well would be added.)

Annual chemical costs are included in the O&M evaluation. The dry cooling arrangement substantially reduces annual chemical use, as the requirement for circulating water chemical treatment is not required. Chemicals will be required for the dry system for the potable and demineralized treatment systems. It was assumed that water steam cycle chemical use is not affected by the means of cooling.

7. VISUAL IMPACT

The air cooled condenser used for dry cooling would be substantially larger than the wet cooling system's cooling tower. The air cooled condenser would have a footprint of approximately 380' x 190'; it would be approximately 117' high. In contrast, the wet tower for Blythe I has a footprint of 472' x 52' and is approximately 41' high.

The air cooled condenser would be taller than all the other structures on the site except for the heat recovery steam generator exhaust (HRSG) stacks. While the air cooled condenser would be 13' shorter that the HRSG stacks, the 18' diameter HRSG stacks would have a much smaller visual impact than the air cooled condenser, which carries its total footprint to the 117' elevation.

The visual impact of the water treatment plant in would be slightly less in the case with an air cooled condenser. The water treatment plant includes an evaporator (brine concentrator). With a wet tower, the evaporator is approximately 98' feet high and 12' in diameter. The evaporator in a plant with dry cooling would be 25' to 30' shorter.

An air cooled condenser would not have a visible plume. Visible plumes will occur infrequently with a wet tower.

8. NOISE IMPACT

The far field noise caused by an air cooled condenser will be greater than that caused by a wet cooling tower for the Blythe plant. The far field sound pressure level caused by an air cooled condenser is expected to be approximately 67 dB(A) at 400'. The noise is generated primarily by fan motors in the condenser. A wet cooling tower would have noise levels of about 60 dB(A) at 400'. Wet tower noise is caused by splash from the cooling tower fill and basin and fan noise.

9. PERFORMANCE

The use of dry cooling has negative impact on plant heat rate. Heat rates for temperatures from 30°F to 114°F and typical relative humidity were calculated for wet and dry systems; the results are provided as Figure 6.

At high ambient temperatures, the heat rate for a dry cooled plant was approximately 6.5% higher than a wet cooled plant under similar ambient conditions. At low ambient temperatures the heat rate was calculated to be approximately 1% higher for the dry cooled arrangement. On an annual average, the heat rate was calculated to be approximately 2% higher for an arrangement with air cooled condensers for the water steam cycle and inlet chilling system as compared to an arrangement with a wet cooling tower and evaporative condenser for the inlet chilling system.

The average heat rate for the plant with a cooling tower and evaporative condenser is estimated to be 6150 BTU/kWh. The annual average for the plant with air cooled condensers is estimated to be 6274 BTU/kWh.

Performance impacts from air cooled condensers are due to the increase in steam turbine backpressure and increase in pressure drops through the condensing system. The ambient dry bulb temperature will limit steam turbine backpressure. At ambient temperatures of 110°F, the steam turbine condensing pressure is approximately 6.5 inches of mercury. Condensing pressure for the arrangement with a wet cooling tower will be dependent on ambient wet bulb temperature. The design wet bulb temperature is 75°F. Condensing pressure at this wet bulb temperature is approximately 2.3 inches of mercury. The increased condensing pressure reduces the steam turbine performance.

Similarly, the refrigerant condensing temperature and pressure will be higher, limited by dry bulb as opposed to wet bulb, for a system with an air cooled condenser. The increased condensing pressure will result in more work from the refrigerant compressors and a worse coefficient of performance for the refrigerant system.

Figure 1,

Blythe Climatic Data

1 **CLIMATIC DATA FROM "SOLAR AND METEORLOGICAL SURFACE OBSERVATION NETWORK 1961-1990"**

Temperature	Ave R.H	Median R.H.	Occurrences	Percent of Total
114	9	8	4	0.0704
110	12	12	61	1.0738
100	20	20	471	8.2908
90	26	28	825	14.5221
80	33	26	921	16.2119
70	32	29	967	17.0217
60	41	41	1,011	17.7962
50	57	54	911	16.0359
40	64	67	450	7.9211
30	64	63	57	1.0033
21	57	62	3	0.0528
			5,681	100

Figure 2

G-ct100.stm

GateCycle Report - SYSTEM Report
Model: CTWR Case: CT100
Prepared using GateCycle Version 5.41.0.r

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12/14/2001

Overall System Results

Model ID	CTWR
Case ID	CT100
Case Description	100F 20%rh
Date & Time of Last Run	12/11/01 07:04
Execution Status	Converged

Case Notes: --
Use this model for initial screening studies of different gas turbines and configurations.
The major inputs are in the User Variables (Inputs Menu)
Macros are used to duplicate HRSG and GT settings in the second train.
Select your gas turbine from the GT library inside the lower gas turbine

Power: --

	Shaft Power	Generator Output	Net Power
Steam Cycle	186679 kW	184812 kW	174676 kW
Gas Turbine	368.84 MW		358.84 MW
Plant Total			533.51 MW

Losses: --

	Generator Losses	Aux & BOP Losses
Steam Cycle	1866.8 kW	10135 kW
Gas Turbine	8307.1 kW	1694.3 kW

LHV Energy Input: --

Total LHV Fuel Cons.	3.31125e+009 BTU/hr
Fuel Cons. in Duct Burners	0.0 BTU/hr

Efficiency: --

	LHV Efficiency	LHV Heat Rate
Gas Turbine	36.98	
Net Cycle	54.97	6206.5 BTU/kW-hr
Adjusted	54.97	6206.5 BTU/kW-hr

Credits Applied for Adjusted Eff. & HR: --

	Equivalent Power	Equivalent Fuel
Credit	0.0 kW	0.0 BTU/hr

Ambient Conditions: --

	Dry Bulb	Wet Bulb	Dew Point
Temperature	100.00 F	69.15 F	51.74 F
	Absolute Pressure	Equivalent Altitude	
Pressure	14.70 psia	0.0 ft	
	Relative Humidity	Water Mole Fraction in Air	
Humidity	0.2000	0.0129183	

User-Defined Variables: --

Index	Description	Value
0	Number of GT-HRSG trains	2
1	Minimum back-end temperature (F	207.50
2	HP throttle pressure (psia)	1451.5
3	RH throttle pressure (psia)	380.18
4	LP throttle pressure (psia)	60.35

GateCycle Report - SYSTEM Report
Model: CTWR Case: CT100
Prepared using GateCycle Version 5.41.0.r

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Figure 3

G-100acc.stm

GateCycle Report - SYSTEM Report
Model: ACCOND Case: 100ACC
Prepared using GateCycle Version 5.41.0.r

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12/14/2001

Overall System Results

Model ID	ACCOND
Case ID	100ACC
Case Description	100 20rh
Date & Time of Last Run	12/13/01 11:22
Execution Status	Converged

Case Notes: --
Use this model for initial screening studies of different gas turbines and configurations.
The major inputs are in the User Variables (Inputs Menu)
Macros are used to duplicate HRSG and GT settings in the second train.
Select your gas turbine from the GT library inside the lower gas turbine

Power: --

	Shaft Power	Generator Output	Net Power
Steam Cycle	173105 kW	171374 kW	157267 kW
Gas Turbine	368.84 MW		358.84 MW
Plant Total			516.10 MW

Losses: --

	Generator Losses	Aux & BOP Losses
Steam Cycle	1731.1 kW	14107 kW
Gas Turbine	8307.0 kW	1694.3 kW

LHV Energy Input: --

Total LHV Fuel Cons.	3.31125e+009 BTU/hr
Fuel Cons. in Duct Burners	0.0 BTU/hr

Efficiency: --

	LHV Efficiency	LHV Heat Rate
Gas Turbine	36.96	
Net Cycle	53.18	6415.9 BTU/kW-hr
Adjusted	53.18	6415.9 BTU/kW-hr

Credits Applied for Adjusted Eff. & HR: --

	Equivalent Power	Equivalent Fuel
Credit	0.0 kW	0.0 BTU/hr

Ambient Conditions: --

	Dry Bulb	Wet Bulb	Dew Point
Temperature	100.00 F	69.13 F	51.74 F
	Absolute Pressure	Equivalent Altitude	
Pressure	14.70 psia	0.0 ft	
	Relative Humidity	Water Mole Fraction in Air	
Humidity	0.2000	0.0129183	

User-Defined Variables: --

Index	Description	Value
0	Number of GT-HRSG trains	2
1	Minimum back-end temperature (F	207.50
2	HP throttle pressure (psia)	1451.5
3	RH throttle pressure (psia)	380.18
4	LP throttle pressure (psia)	60.35

□

GateCycle Report - SYSTEM Report
Model: ACCOND Case: 100ACC
Prepared using GateCycle Version 5.41.0.r

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Figure 4

Wet vs. Dry Capital Costs

Capital Costs	Wet Cooling System	Dry Cooling System
Condenser	$2,000,000	NA
Cooling Tower (Erected)	$3,000,000	NA
Circulating Water Pumps	$600,000	NA
Condensate Extraction Pumps	$400,000	
Air Cooled Condenser		23,500,000
Evaporation Ponds	$3,200,000	1,200,000
Water Treatment Equipment (Erected)	$7,500,000	3,000,000
Construction Costs	$1,200,000	9,400,000
Added Engineering Costs	N/A	500,000
Changes to Reference Plant Steam Turbine Hall	N/A	1,500,000
Well pump	$600,000	N/A
Interest During Construction (10%)	$ 1,850,000	3,910,000
Total Capital	**$20,350,000**	**$43,010,000**
Difference:	**$22,660,000**	

Figure 5

Wet vs. Dry O&M Costs

O&M for water treatment and fan power	Wet Cooling System			Dry Cooling System
Cooling Tower Fans (8x160HP)		5,561,221	kWH	N/A
		$139,031		
Water Treatment System (1.2 MW/0.24MW)		10,816,000	kWH	2,163,200
		$270,400		$54,080
Air Cooled Condenser Fans (50x164 HP)	N/A			35,626,573
				$890,664
Circulating Water Pumps (2x1100 HP)		13,654,784	kWH	N/A
		$341,370		
Chilling System Energy Use		21,591,000		39,220,000
		$539,775		$980,500
Well Pump Energy Use		1,076,245		
		$26,906		
Chemicals, $/YR		$350,000		$50,000
Total O&M		**$1,667,481**		**$1,975,244**
Difference:		**$307,763**		
NPV of O&M for 30 years at 10% and 2.5% escalation		**$3,282,055**		

Sum of Difference in Capital and O&M Costs: $25,942,055

Figure 6

Heat Rate Comparison for Wet and Dry Cooling

Ambient Temperature °F	Relative Humidity	Cooling Tower Heat Rate	Air Cooled Condenser Heat Rate	Delta	Delta %
114	9%	6222	6631	409	6.58
110	12%	6217	6576	359	5.77
100	20%	6206	6460	254	4.08
90	26%	6188	6363	175	2.83
80	33%	6169	6302	133	2.15
70	32%	6151	6263	112	1.83
60	41%	6134	6229	95	1.54
50	57%	6122	6193	71	1.15
40	64%	6106	6162	56	0.91
30	64%	6093	6188	95	1.56

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of:	**Docket No. 02-AFC-1**
Application for Certification for the BLYTHE ENERGY PROJECT- PHASE II	**PROOF OF SERVICE** **(*Revised on 11/24/03*)**

I, ***Evelyn M Johnson***, declare that on ***August 9, 2004***, I deposited copies of the attached **RE: REVISED Comments to the "DRAFT" PSD Permit,** in the United States mail at *Sacramento, CA* with first class postage thereon fully prepaid and addressed to the following:

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Send the original signed document plus the required 12 copies to the address below:

CALIFORNIA ENERGY COMMISSION
DOCKET UNIT, MS-4
Attn: Docket No. 02-AFC-1
1516 Ninth Street
Sacramento, CA 95814-5512

* * * *

In addition to the documents sent to the Commission Docket Unit, also send individual copies of any documents to:

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I declare under penalty of perjury that the foregoing is true and correct

Evelyn M Johnson
[signature]

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*   *   *   *

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